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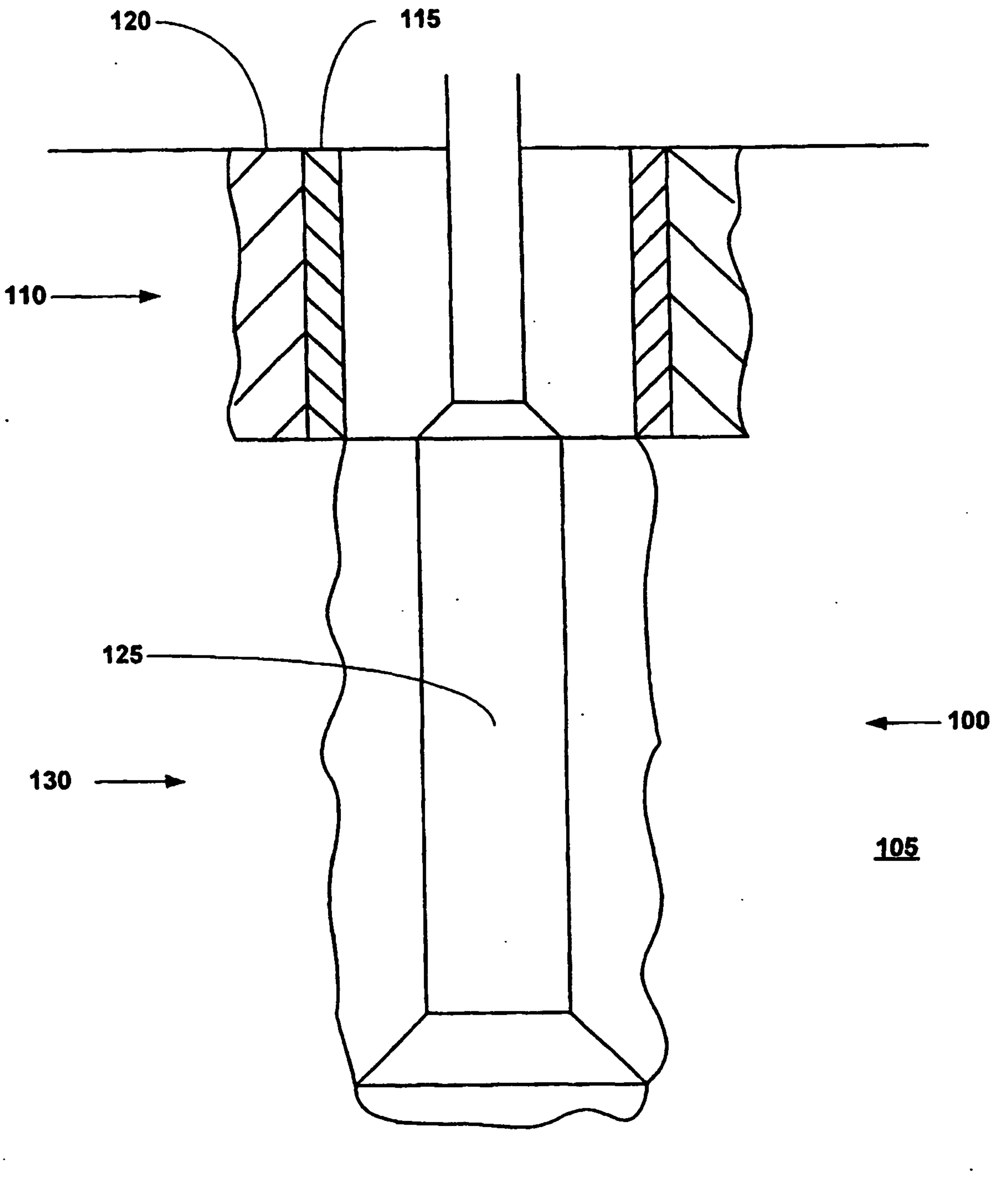
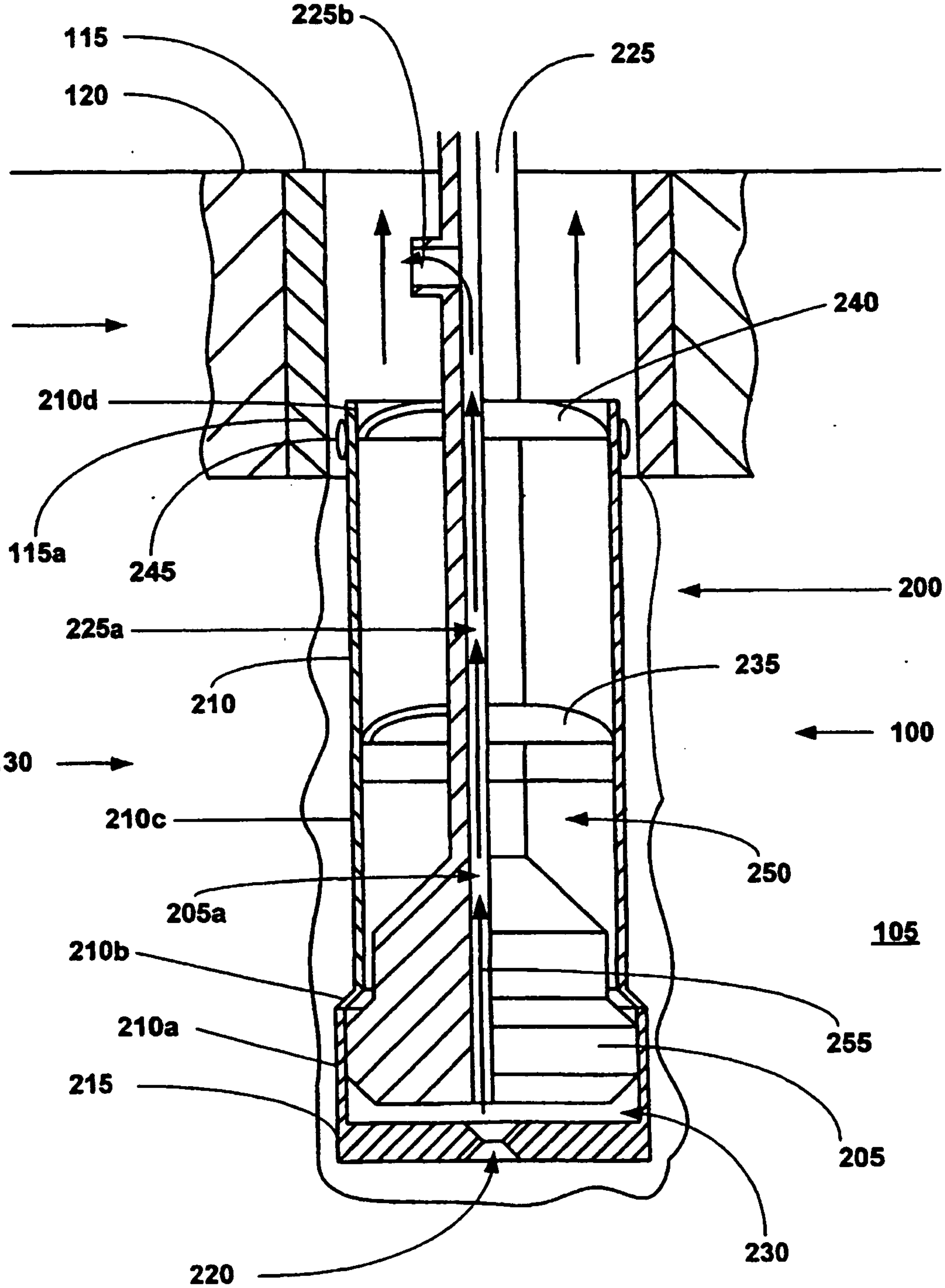


FIGURE 1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115
225
120
110
240
210d
115a
245
200
225a
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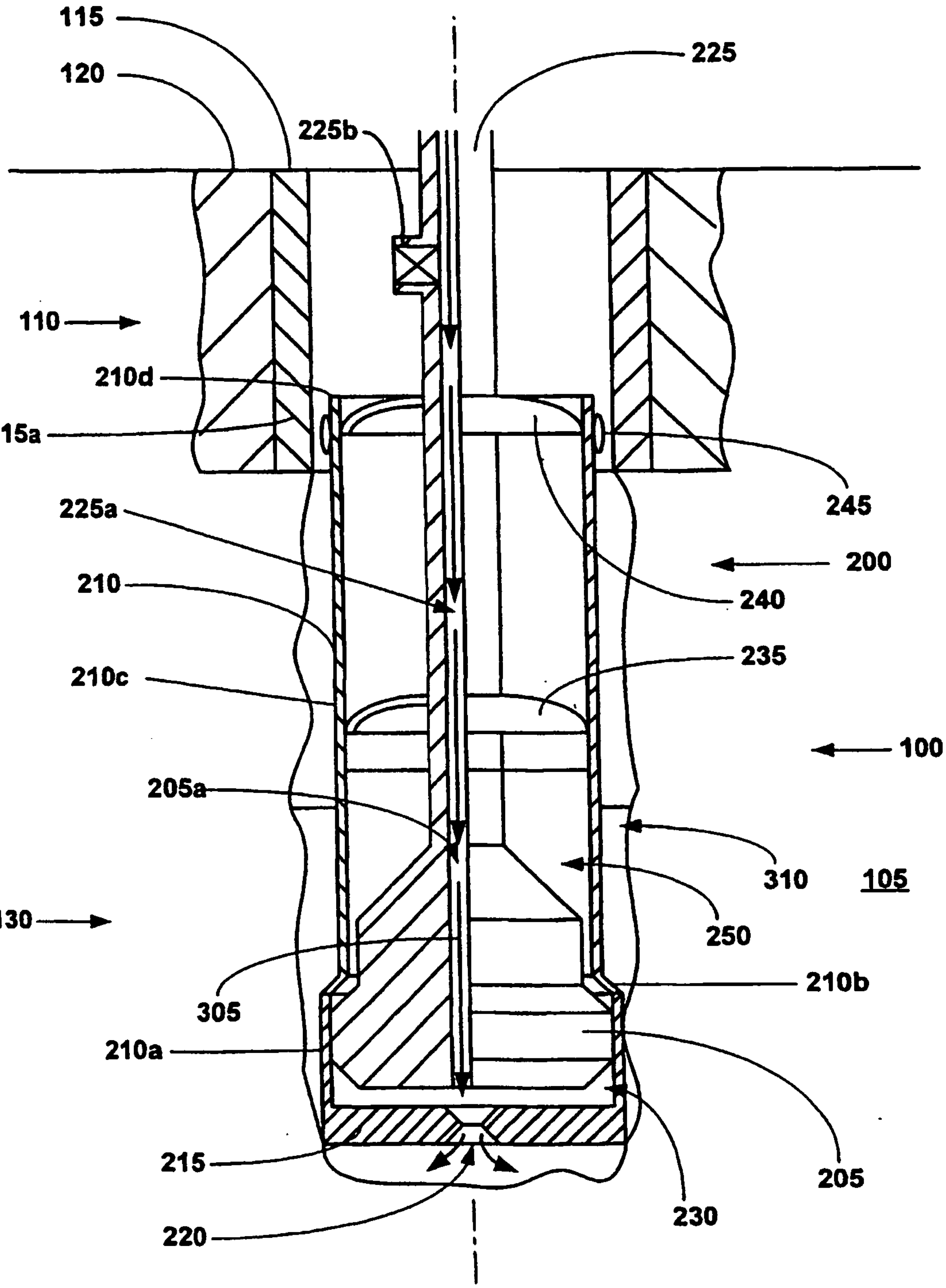
100
130
210c
250
205a
105
210b
255
210a
205
215
230
220

FIGURE 2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210d
115a
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225a
200
210
240
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205a
310
105
250
130
210b
305
210a
205
215
230
220

FIGURE 3

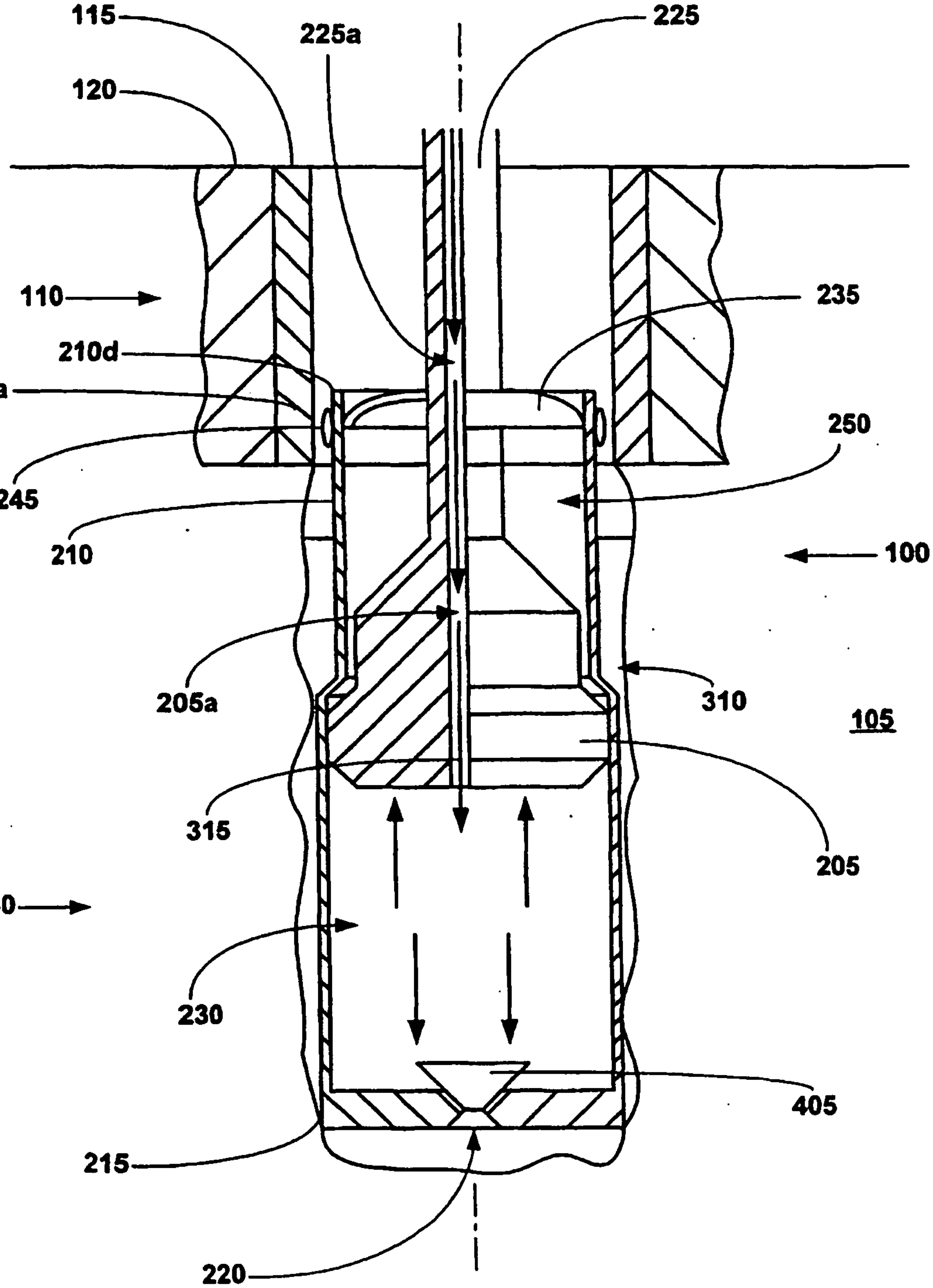

115
225a
225
120
110
235
210d
115a
250
245
210
100
205a
310
105
315
205
130
230
405
215
220

FIGURE 4

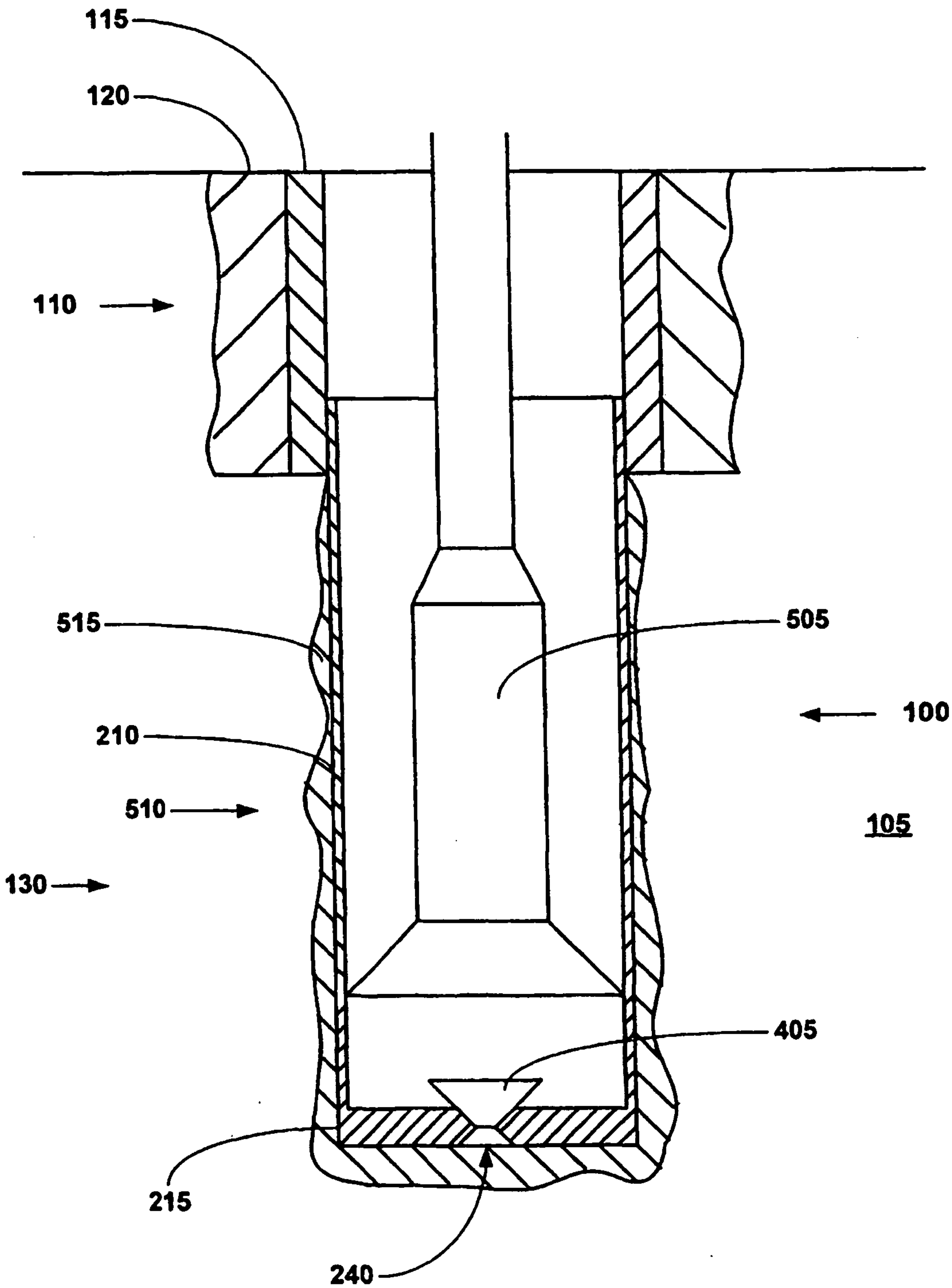


FIGURE 5

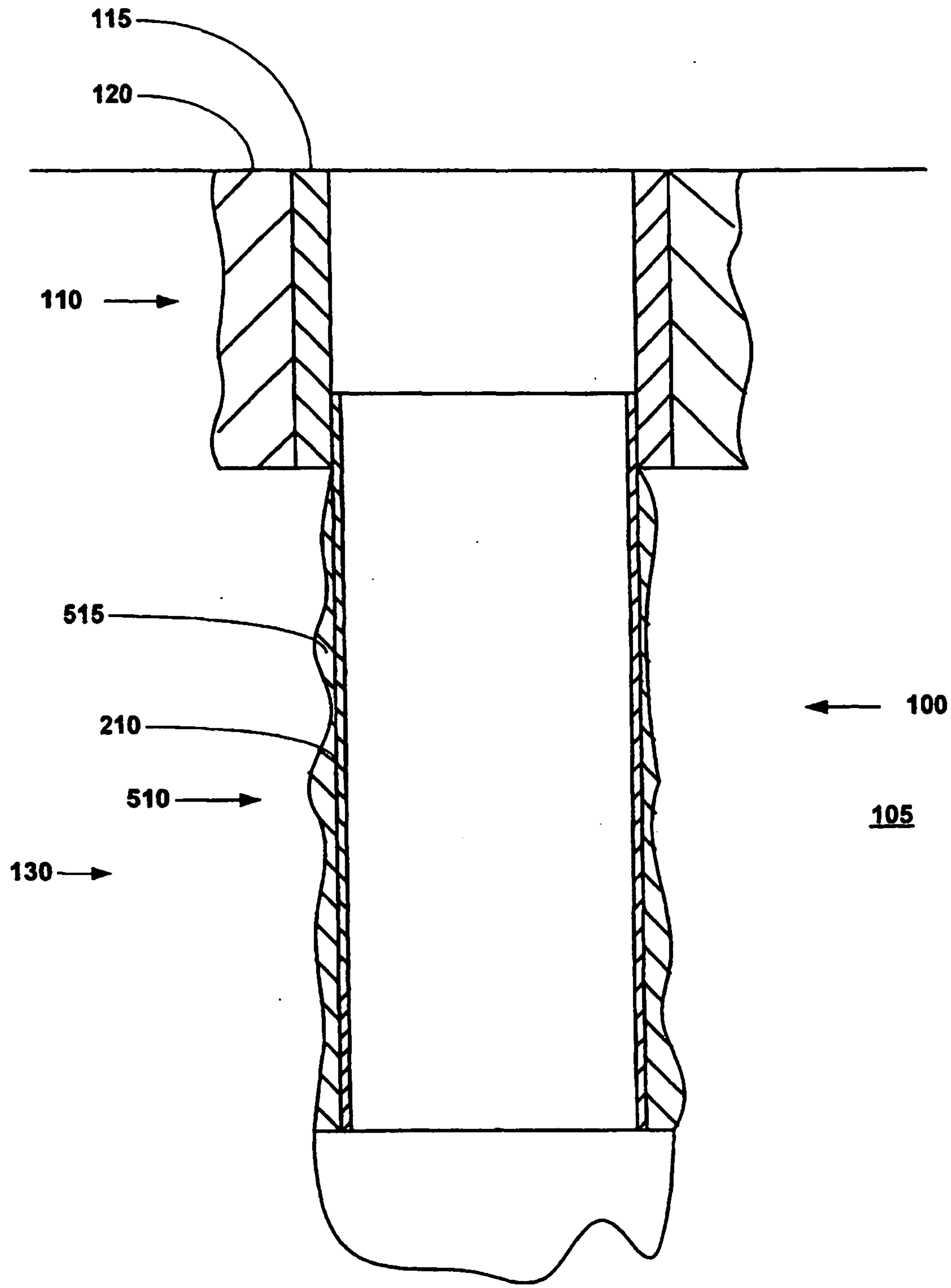
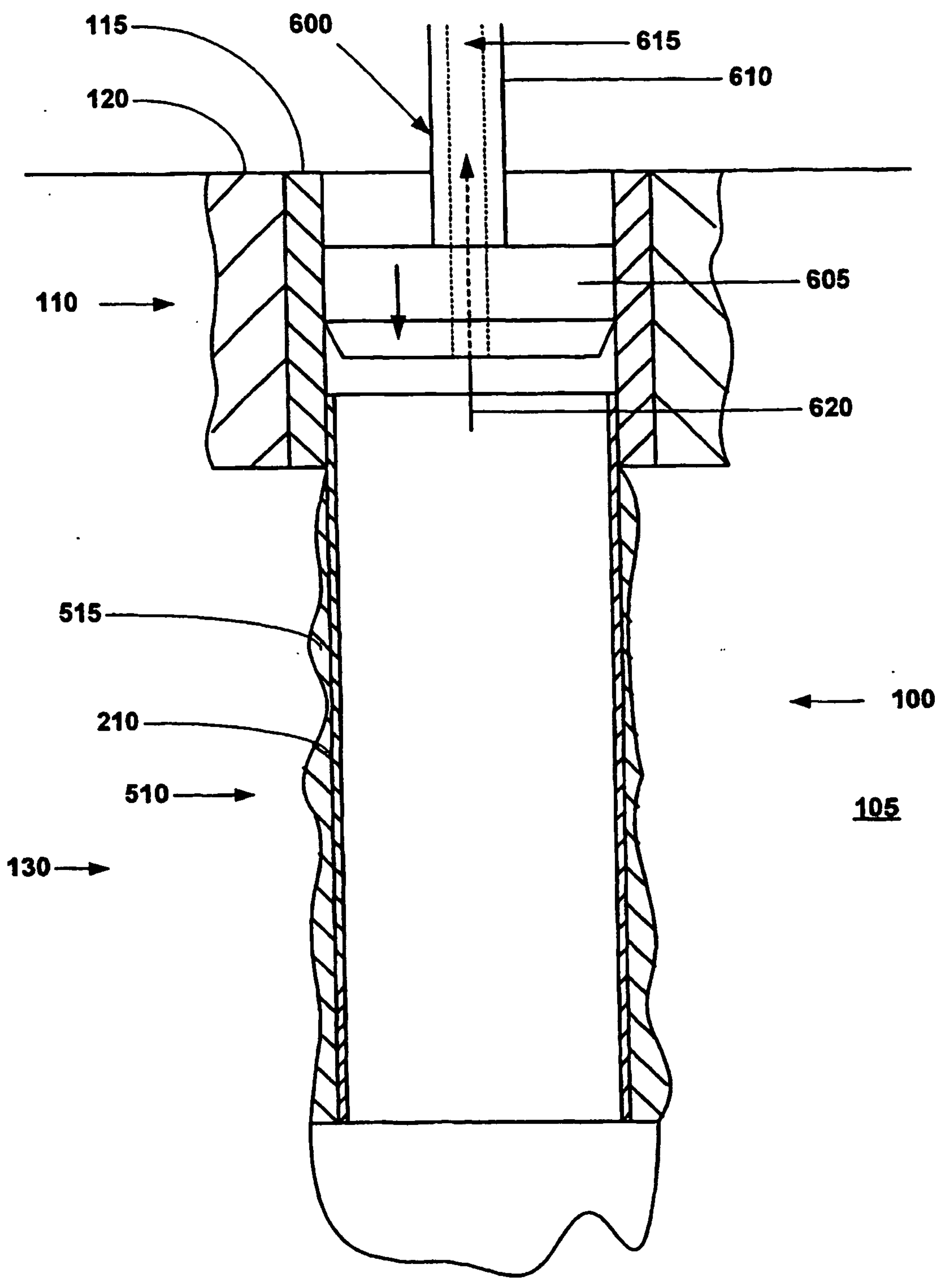


FIGURE 6



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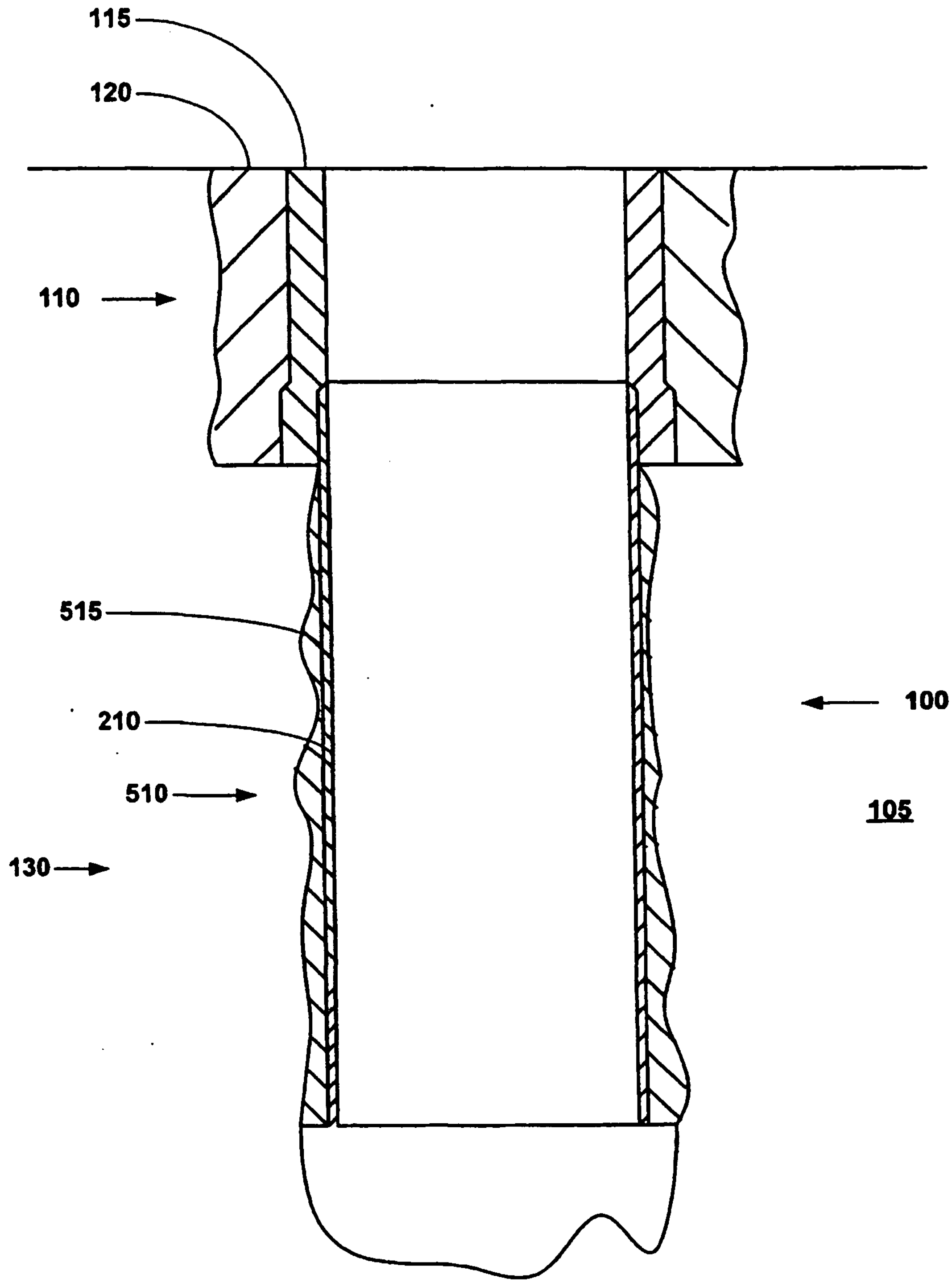


FIGURE 8

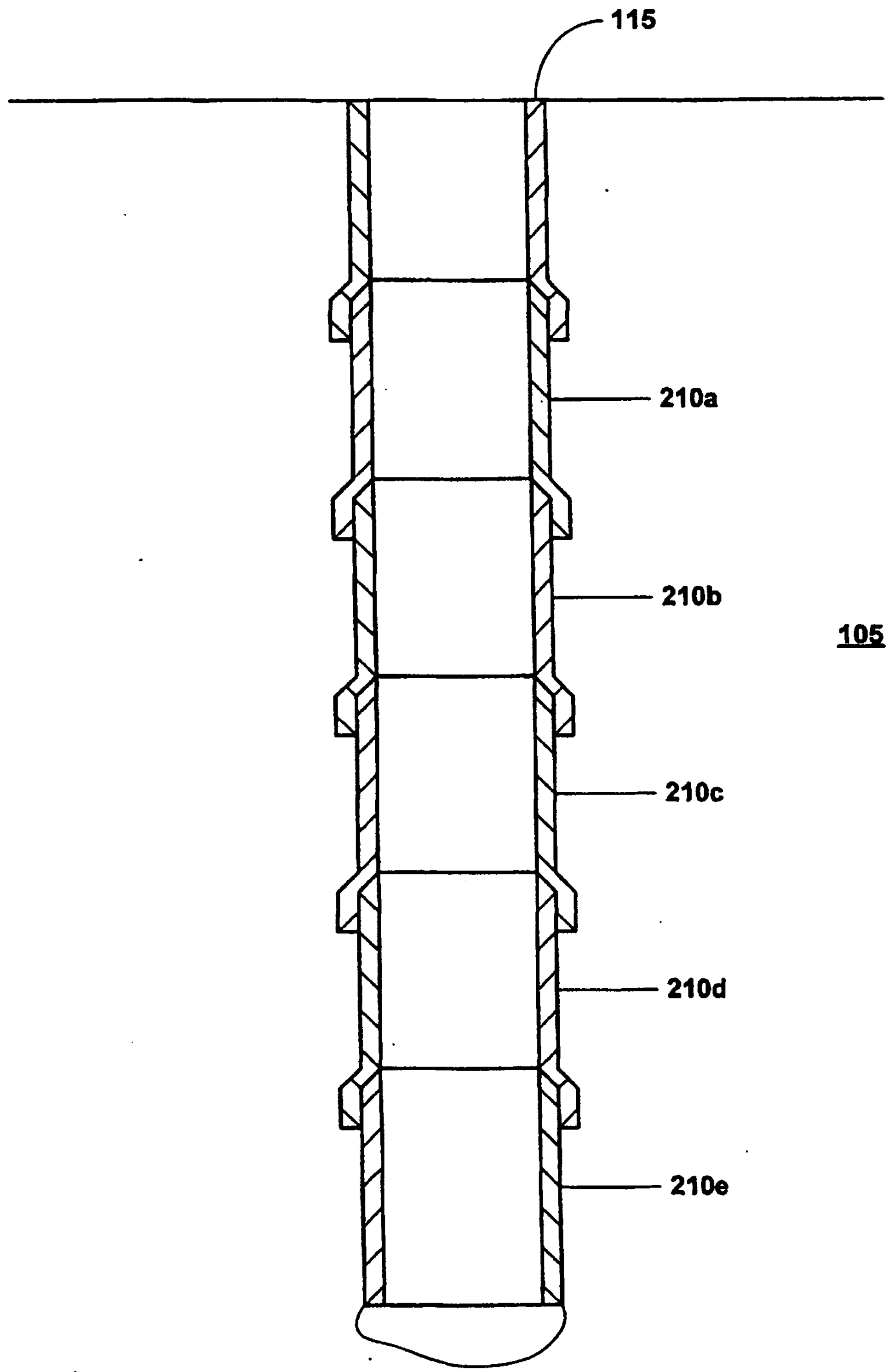
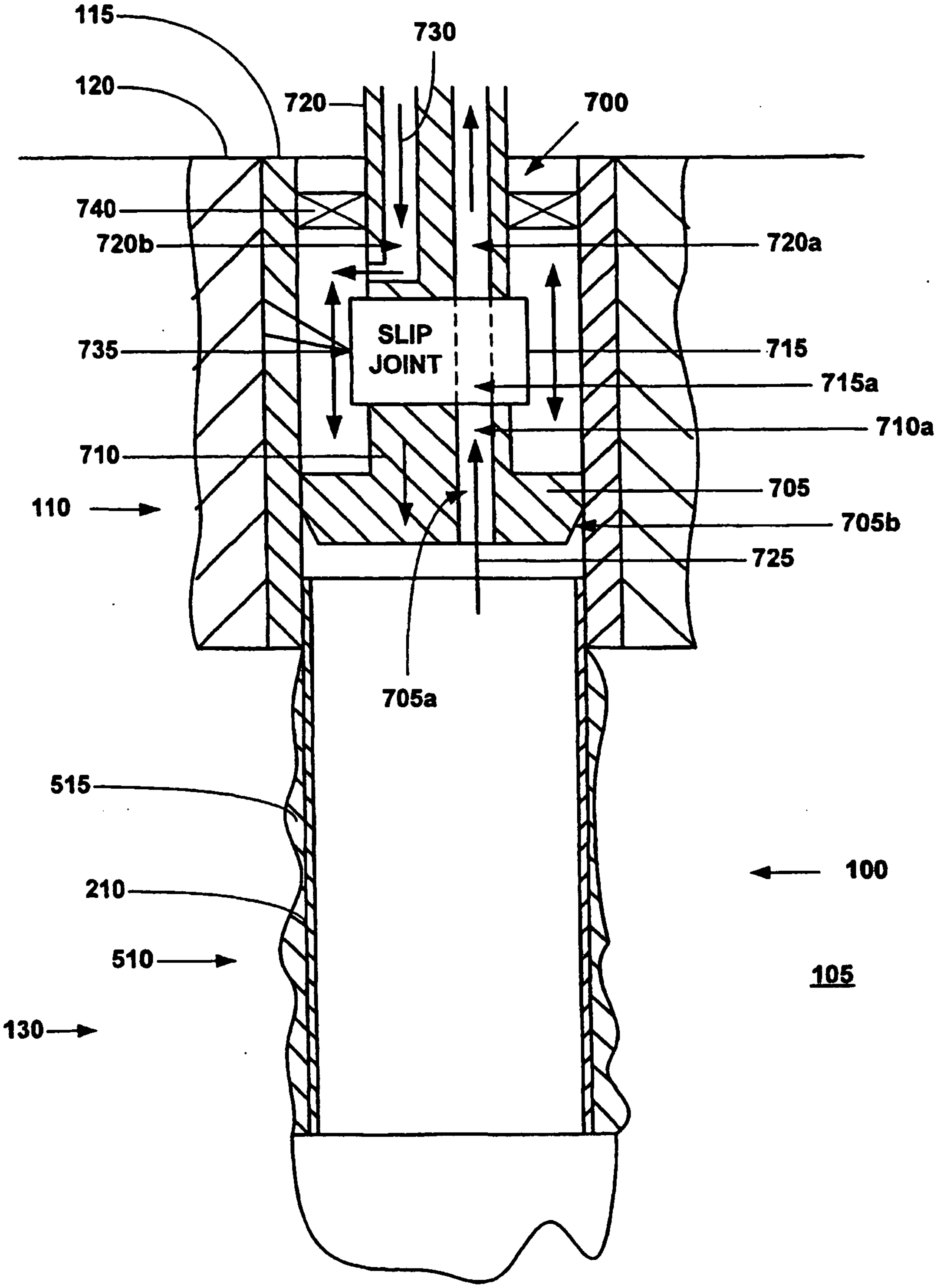


FIGURE 9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120
730
720
700
740
720b
720a
SLIP JOINT
735
715
715a
710a
710
705
110
705b
725
705a
515
100
210
510
105
130

FIGURE 10

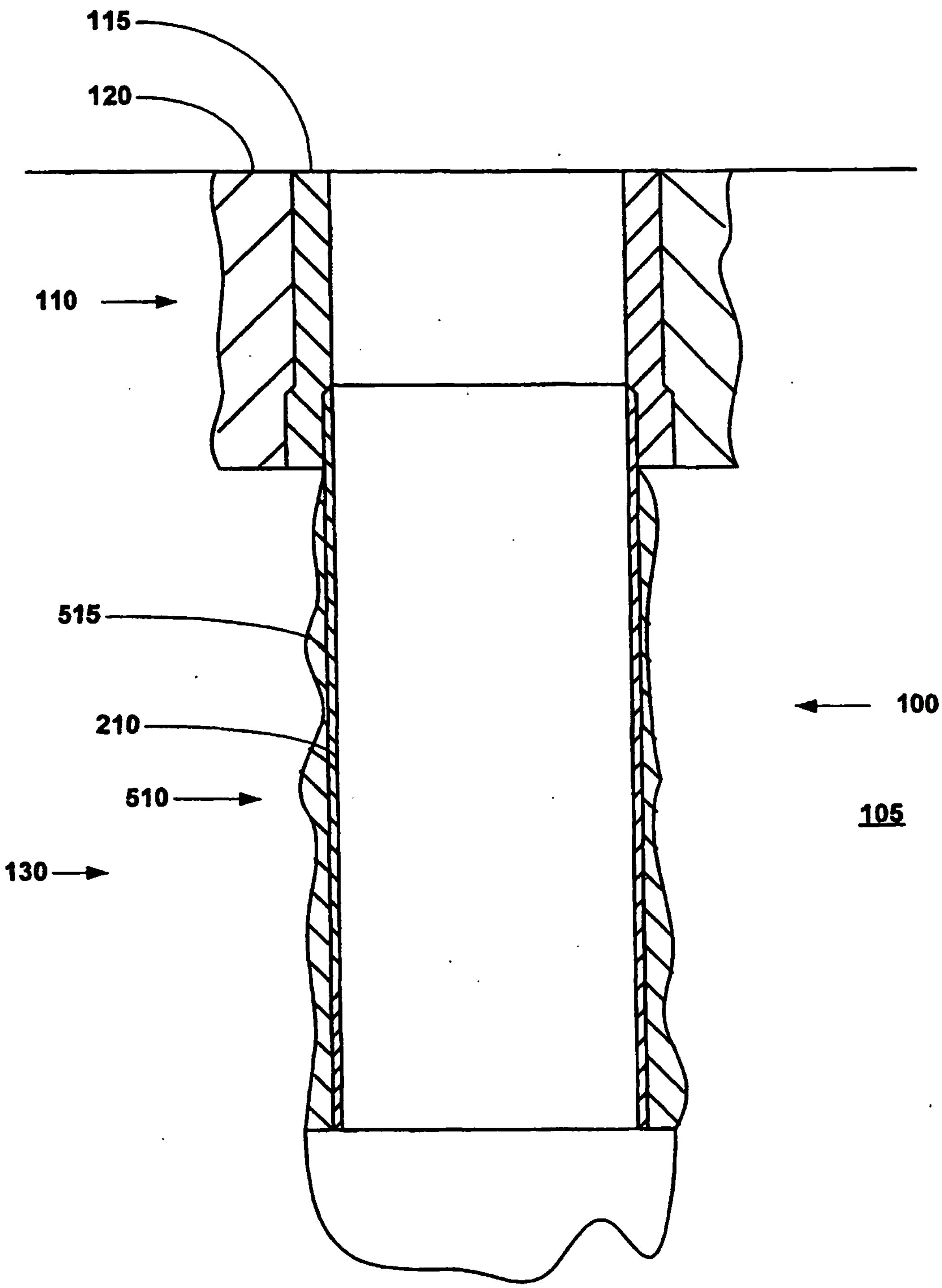
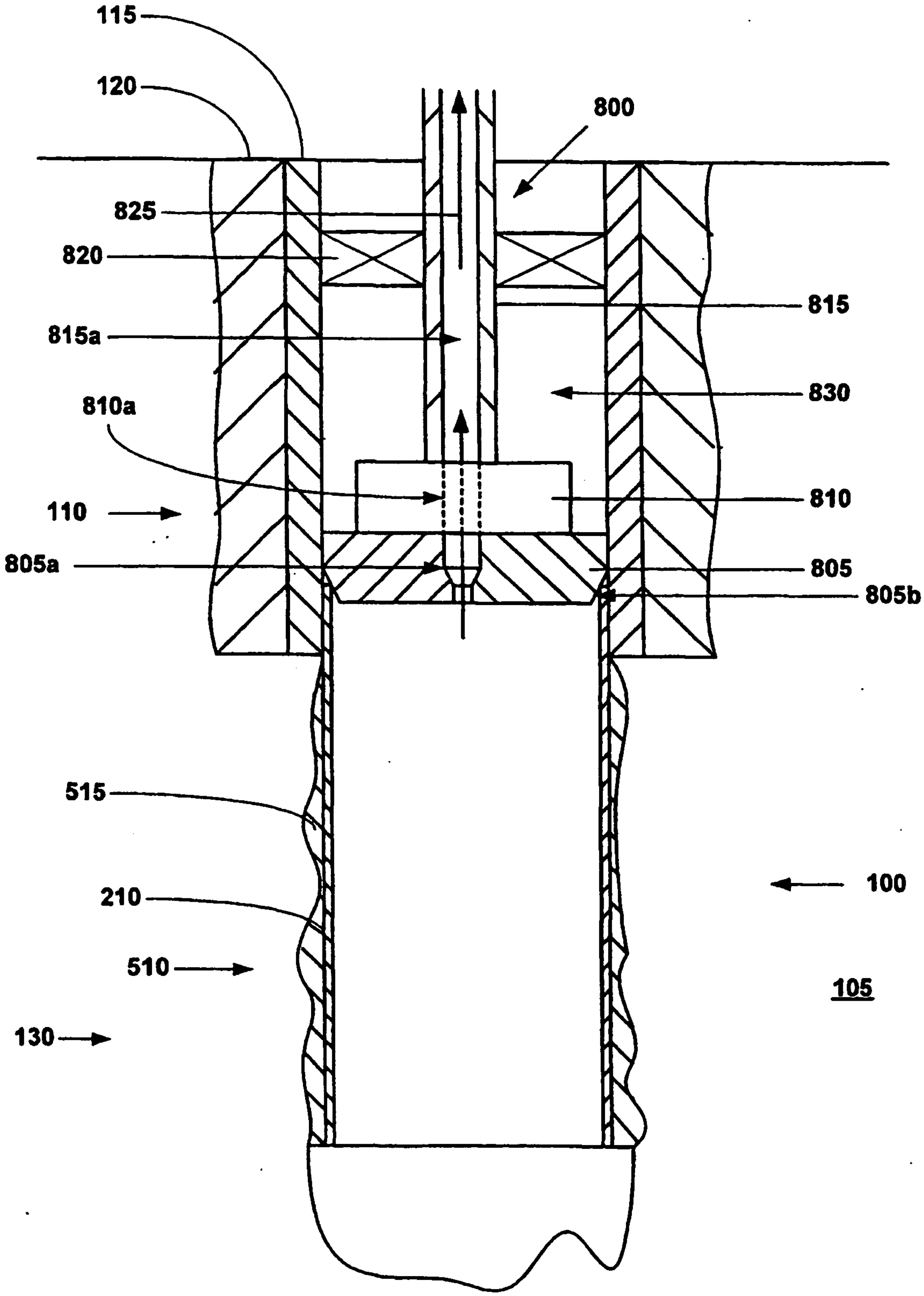


FIGURE 11


115
120
800
825
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815
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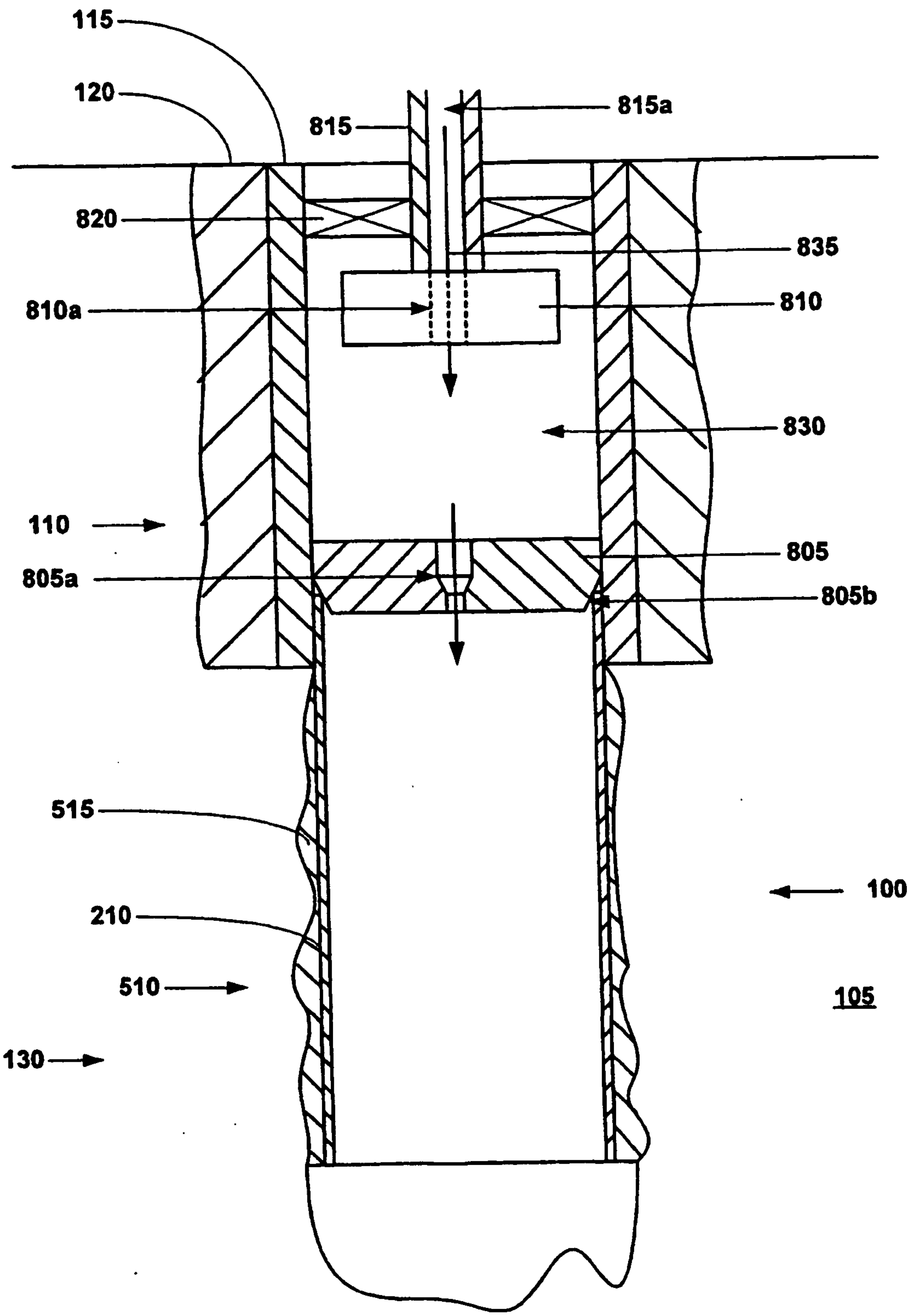
810a
810
110
805a
805
805b
515
100
210
510
105
130

FIGURE 12


115
120
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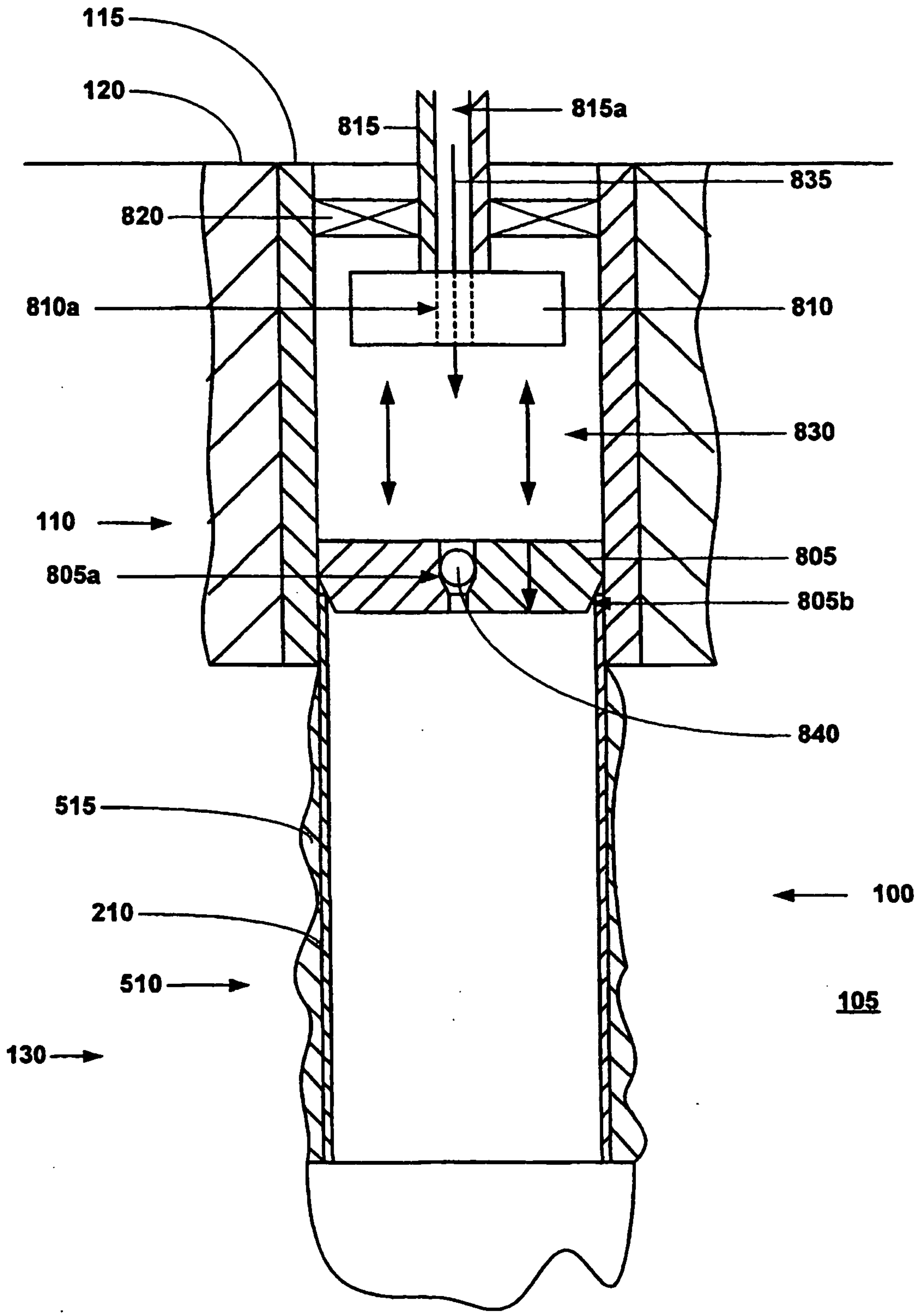
805
805a
805b
515
100
210
510
105
130

FIGURE 13


115
120
815
815a
835
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810a
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830
110
805
805a
805b
840
515
100
210
510
105
130

FIGURE 14

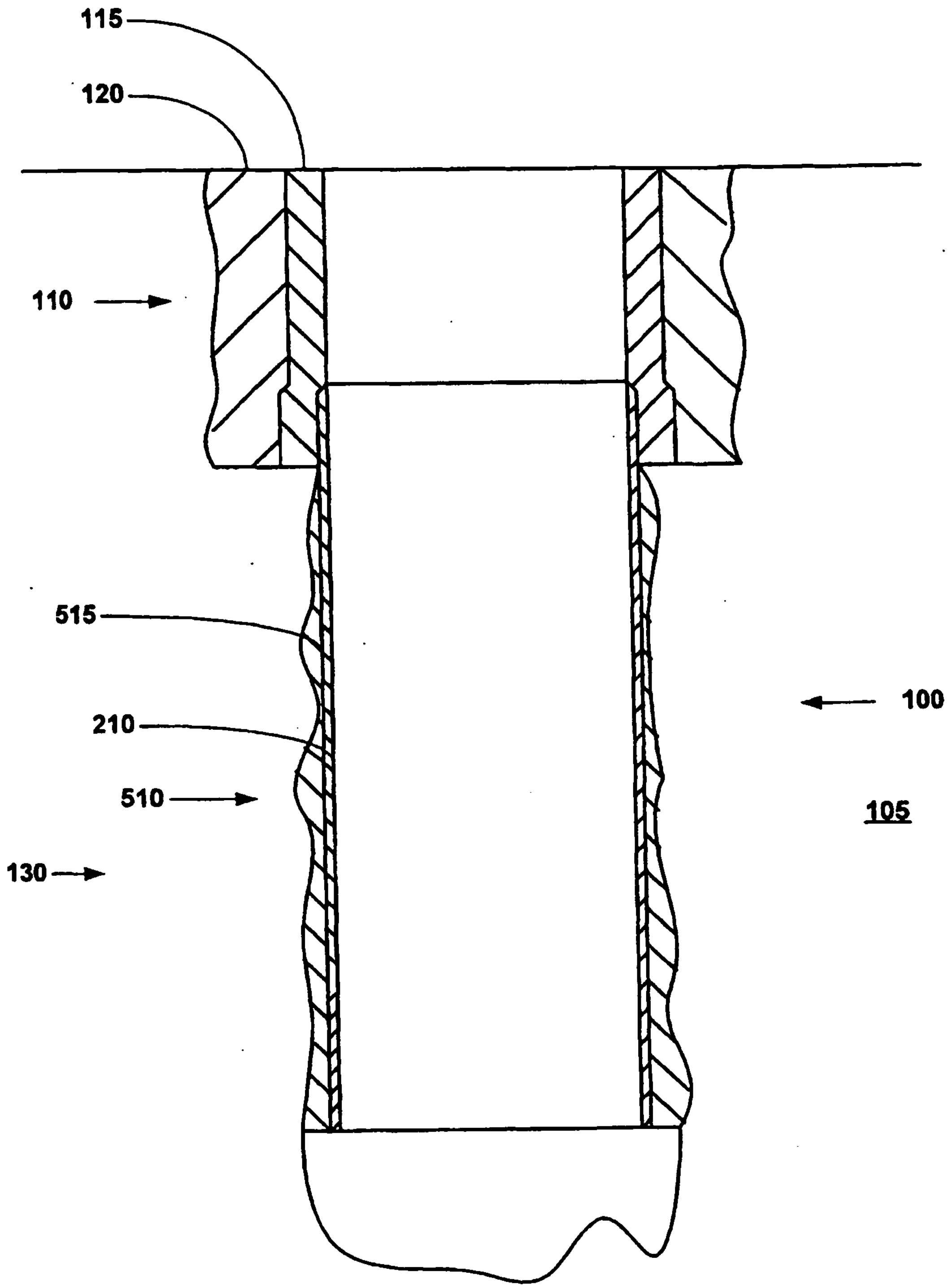

FIGURE 15

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MONO-DIAMETER WELLBORE CASING

This invention relates generally to wellbore casings, and in particular to wellbore casings that are formed using expandable tubing.

Conventionally, when a wellbore is created, a number of casings are installed in the borehole to prevent collapse of the borehole wall and to prevent undesired outflow of drilling fluid into the formation or inflow of fluid from the formation into the borehole. The borehole is drilled in intervals whereby a casing which is to be installed in a lower borehole interval is lowered through a previously installed casing of an upper borehole interval. As a consequence of this procedure the casing of the lower interval is of smaller diameter than the casing of the upper interval. Thus, the casings are in a nested arrangement with casing diameters decreasing in downward direction. Cement annuli are provided between the outer surfaces of the casings and the borehole wall to seal the casings from the borehole wall. As a consequence of this nested arrangement a relatively large borehole diameter is required at the upper part of the wellbore. Such a large borehole diameter involves increased costs due to heavy casing handling equipment, large drill bits and increased volumes of drilling fluid and drill cuttings. Moreover, increased drilling rig time is involved due to required cement pumping, cement hardening, required equipment changes due to large variations in hole diameters drilled in the course of the well, and the large volume of cuttings drilled and removed.

The present invention is directed to overcoming one or more of the limitations of the existing procedures for forming new sections of casing in a wellbore.

Summary of the Invention

According to one aspect of the present invention there is provided a method of radially expanding an overlapping joint between a wellbore casing and a tubular liner, comprising:

positioning an expansion cone within the wellbore casing above the overlapping joint;

sealing off a region within the wellbore casing above the expansion cone;

releasing the expansion cone;

displacing the expansion cone by pressurizing an annular region; and

pressurizing the interior of the tubular liner.

According to another aspect of the present invention there is provided an apparatus for radially expanding an overlapping joint between a wellbore casing and a tubular liner, comprising:

means for positioning an expansion cone within the wellbore casing above the overlapping joint;

means for sealing off a region within the wellbore casing above the expansion cone;

means for releasing the expansion cone;

means for displacing the expansion cone by pressurizing an annular region; and

means for pressurizing the interior of the tubular liner.

According to another aspect of the present invention there is provided a method of radially expanding an overlapping joint between first and second tubular members, comprising:

positioning an expansion cone within the first tubular member above the overlapping joint;

sealing off a region within the first tubular member above the expansion cone; releasing the expansion cone;

displacing the expansion cone by pressurizing an annular region; and

pressurizing the interior of the second tubular member.

According to another aspect of the present invention there is provided an apparatus for radially expanding an overlapping joint between first and second tubular members, comprising:

means for positioning an expansion cone within the first tubular member above the overlapping joint;

means for sealing off a region within the first tubular member above the expansion cone;

means for releasing the expansion cone;

means for displacing the expansion cone by pressurizing an annular region; and

means for pressurizing the interior of the second tubular member.

The invention will now be described with reference to the accompanying drawings, in which Figures 12 to 14 show embodiments of the invention. The other drawings are included for illustrative purposes only.

Brief Description of the Drawings

FIG. 1 is a fragmentary cross-sectional view illustrating the drilling of a new section of a well borehole.

FIG. 2 is a fragmentary cross-sectional view illustrating the placement of an apparatus for creating a casing within the new section of the well borehole of FIG. 1.

FIG. 3 is a fragmentary cross-sectional view illustrating the injection of a hardenable fluidic sealing material into the new section of the well borehole of FIG. 2.

FIG. 4 is a fragmentary cross-sectional view illustrating the injection of a fluidic material into the new section of the well borehole of FIG. 3.

FIG. 5 is a fragmentary cross-sectional view illustrating the drilling out of the cured hardenable fluidic sealing material and the shoe from the new section of the well borehole of FIG. 4.

FIG. 6 is a cross-sectional view of the well borehole of FIG. 5 following the drilling out of the shoe.

FIG. 7 is a fragmentary cross-sectional view of the placement and actuation of a second expansion cone within the well borehole of FIG. 6 for forming a mono-diameter wellbore casing.

FIG. 8 is a cross-sectional illustration of the well borehole of FIG. 7 following the formation of a mono-diameter wellbore casing.

FIG. 9 is a cross-sectional illustration of the well borehole of FIG. 8 following the repeated operation of the methods of FIGS. 1-8 in order to form a

mono-diameter wellbore casing including a plurality of overlapping wellbore casings.

FIG. 10 is a fragmentary cross-sectional illustration of the placement of a second expansion cone for forming a mono-diameter wellbore casing into the well borehole of FIG. 6.

FIG. 11 is a cross-sectional illustration of the well borehole of FIG. 10 following the formation of a mono-diameter wellbore casing.

FIG. 12 is a fragmentary cross-sectional illustration of the placement of an embodiment of a second expansion cone for forming a mono-diameter wellbore casing into the well borehole of FIG. 6.

FIG. 13 is a fragmentary cross-sectional illustration of the well borehole of FIG. 12 during the injection of pressurized fluids into the well borehole.

FIG. 14 is a fragmentary cross-sectional illustration of the well borehole of FIG. 13 during the formation of the mono-diameter wellbore casing.

FIG. 15 is a fragmentary cross-sectional illustration of the well borehole of FIG. 14 following the formation of the mono-diameter wellbore casing.

Detailed Description

Referring initially to FIGS. 1-9, an apparatus and method for forming a mono-diameter wellbore casing within a subterranean formation will now be described. As illustrated in Fig. 1, a wellbore 100 is positioned in a subterranean formation 105. The wellbore 100 includes a pre-existing cased section 110 having a tubular casing 115 and an annular outer layer 120 of a fluidic sealing material such as, for example, cement. The wellbore 100 may be positioned in any orientation from vertical to horizontal. In alternative arrangements, the pre-existing cased section 110 does not include the annular outer layer 120.

In order to extend the wellbore 100 into the subterranean formation 105, a drill string 125 is used in a well known manner to drill out material from the subterranean formation 105 to form a new wellbore section 130.

As illustrated in FIG. 2, an apparatus 200 for forming a wellbore casing in a subterranean formation is then positioned in the new section 130 of the wellbore

100. The apparatus 200 includes an expansion cone 205 having a fluid passage 205a that supports a tubular member 210 that includes a lower portion 210a, an intermediate portion 210b, an upper portion 210c, and an upper end portion 210d.

The expansion cone 205 may be any number of conventional commercially available expansion cones. For example, the expansion cone 205 may be controllably expandable in the radial direction, for example, as disclosed in U.S. patent nos. 5,348,095, and/or 6,012,523, the disclosures of which are incorporated herein by reference.

The tubular member 210 may be fabricated from any number of conventional commercially available materials such as, for example, Oilfield Country Tubular Goods (OCTG), 13 chromium steel tubing/casing, or plastic tubing/casing. The tubular member 210 is preferably fabricated from OCTG in order to maximize strength after expansion. Alternatively, the tubular member 210 may be solid and/or slotted. The length of the tubular member 210 is limited to minimize the possibility of buckling. For typical tubular member 210 materials, the length of the tubular member 210 is preferably limited to between about 40 to 20,000 feet in length.

The lower portion 210a of the tubular member 210 has a larger inside diameter than the upper portion 210c of the tubular member. The wall thickness of the intermediate portion 210b of the tubular member 201 is less than the wall thickness of the upper portion 210c of the tubular member in order to facilitate the initiation of the radial expansion process. The upper end portion 210d of the tubular member 210 is slotted, perforated, or otherwise modified to catch or slow down the expansion cone 205 when it completes the extrusion of tubular member 210.

A shoe 215 is coupled to the lower portion 210a of the tubular member. The shoe 215 includes a valveable fluid passage 220 that is adapted to receive a plug, dart, or other similar element for controllably sealing the fluid passage 220. In this manner, the fluid passage 220 may be optimally sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage 240.

The shoe 215 may be one of any number of conventional commercially available shoes such as, for example, Super Seal II float shoe, Super Seal II Down-

Jet float shoe or a guide shoe with a sealing sleeve for a latch down plug modified in accordance with the teachings of the present disclosure. In a preferred arrangement, the shoe 215 is an aluminum down-jet guide shoe with a sealing sleeve for a latch-down plug available from Halliburton Energy Services in Dallas, TX, modified in accordance with the teachings of the present disclosure, in order to optimally guide the tubular member 210 in the wellbore, optimally provide an adequate seal between the interior and exterior diameters of the overlapping joint between the tubular members, and to optimally allow the complete drill out of the shoe and plug after the completion of the cementing and expansion operations.

The shoe 215 further includes one or more through and side outlet ports in fluidic communication with the fluid passage 220. In this manner, the shoe 215 optimally injects hardenable fluidic sealing material into the region outside the shoe 215 and tubular member 210.

A support member 225 having fluid passages 225a and 225b is coupled to the expansion cone 205 for supporting the apparatus 200. The fluid passage 225a is preferably fluidicly coupled to the fluid passage 205a. In this manner, fluidic materials may be conveyed to and from a region 230 below the expansion cone 205 and above the bottom of the shoe 215. The fluid passage 225b is fluidicly coupled to the fluid passage 225a and includes a conventional control valve. In this manner, during placement of the apparatus 200 within the wellbore 100, surge pressures can be relieved by the fluid passage 225b. The support member 225 further includes one or more conventional centralizers (not illustrated) to help stabilize the apparatus 200.

During placement of the apparatus 200 within the wellbore 100, the fluid passage 225a is selected to transport materials such as, for example, drilling mud or formation fluids at flow rates and pressures ranging from about 0 to 11.355 m^3/minute (0 to 3,000 gallons/minute) and 0 to 62.052 x 10^3 KPa (0 to 9,000 psi) in order to minimize drag on the tubular member being run and to minimize surge pressures exerted on the wellbore 130 which could cause a loss of wellbore fluids and lead to hole collapse. During placement of the apparatus 200 within the wellbore 100, the fluid passage 225b is preferably selected to convey fluidic

materials at flow rates and pressures ranging from about 0 to 11.355 m^3/minute (0 to 3,000 gallons/minute) and 0 to 62.052 x 10^3 KPa (0 to 9,000 psi) in order to reduce the drag on the apparatus 200 during insertion into the new section 130 of the wellbore 100 and to minimize surge pressures on the new wellbore section 130.

A lower cup seal 235 is coupled to and supported by the support member 225. The lower cup seal 235 prevents foreign materials from entering the interior region of the tubular member 210 adjacent to the expansion cone 205. The lower cup seal 235 may be one of any number of conventional commercially available cup seals such as, for example, TP cups, or Selective Injection Packer (SIP) cups modified in accordance with the teachings of the present disclosure. In a preferred arrangement, the lower cup seal 235 is a SIP cup seal, available from Halliburton Energy Services in Dallas, TX in order to optimally block foreign material and contain a body of lubricant.

The upper cup seal 240 is coupled to and supported by the support member 225. The upper cup seal 240 prevents foreign materials from entering the interior region of the tubular member 210. The upper cup seal 240 may be one of any number of conventional commercially available cup seals such as, for example, TP cups or SIP cups modified in accordance with the teachings of the present disclosure. In a preferred arrangement, the upper cup seal 240 is a SIP cup, available from Halliburton Energy Services in Dallas, TX in order to optimally block the entry of foreign materials and contain a body of lubricant.

One or more sealing members 245 are coupled to and supported by the exterior surface of the upper end portion 210d of the tubular member 210. The seal members 245 provide an overlapping joint between the lower end portion 115a of the casing 115 and the portion 260 of the tubular member 210 to be fluidicly sealed. The sealing members 245 may be selected from any number of conventional commercially available seals such as, for example, lead, rubber, Teflon(RTM), or epoxy seals modified in accordance with the teachings of the present disclosure. The sealing members 245 are preferably molded from Stratalock epoxy available from Halliburton Energy Services in Dallas, TX in order to optimally provide a load

bearing interference fit between the upper end portion 210d of the tubular member 210 and the lower end portion 115a of the existing casing 115.

The sealing members 245 are selected to optimally provide a sufficient frictional force to support the expanded tubular member 210 from the existing casing 115. The frictional force optimally provided by the sealing members 245 ranges from about 4.448×10^3 to 4.448×10^6 N (1,000 to 1,000,000 lbf) in order to optimally support the expanded tubular member 210.

A quantity of lubricant 250 is provided in the annular region above the expansion cone 205 within the interior of the tubular member 210. In this manner, the extrusion of the tubular member 210 off of the expansion cone 205 is facilitated. The lubricant 250 may be any number of conventional commercially available lubricants such as, for example, Lubriplate$^{(RTM)}$, chlorine based lubricants, oil based lubricants or Climax 1500 Antisieze (3100). In a preferred arrangement, the lubricant 250 is Climax 1500 Antisieze (3100) available from Climax Lubricants and Equipment Co. in Houston, TX in order to optimally provide optimum lubrication to facilitate the expansion process.

The support member 225 is thoroughly cleaned prior to assembly to the remaining portions of the apparatus 200. In this manner, the introduction of foreign material into the apparatus 200 is minimized. This minimizes the possibility of foreign material clogging the various flow passages and valves of the apparatus 200.

Before or after positioning the apparatus 200 within the new section 130 of the wellbore 100, a couple of wellbore volumes are circulated in order to ensure that no foreign materials are located within the wellbore 100 that might clog up the various flow passages and valves of the apparatus 200 and to ensure that no foreign material interferes with the expansion process.

As illustrated in FIG. 2, during placement of the apparatus 200 within the wellbore 100, fluidic materials 255 within the wellbore that are displaced by the apparatus are conveyed through the fluid passages 220, 205a, 225a, and 225b. In this manner, surge pressures created by the placement of the apparatus within the wellbore 100 are reduced.

As illustrated in FIG. 3, the fluid passage 225b is then closed and a hardenable fluidic sealing material 305 is then pumped from a surface location into the fluid passages 225a and 205a. The material 305 then passes from the fluid passage 205a into the interior region 230 of the tubular member 210 below the expansion cone 205. The material 305 then passes from the interior region 230 into the fluid passage 220. The material 305 then exits the apparatus 200 and fills an annular region 310 between the exterior of the tubular member 210 and the interior wall of the new section 130 of the wellbore 100. Continued pumping of the material 305 causes the material 305 to fill up at least a portion of the annular region 310.

The material 305 is preferably pumped into the annular region 310 at pressures and flow rates ranging, for example, from about 0 to 34.474 X 10^3 KPa (0 to 5000 psi) and 0 to 5.6775 m^3/minute (0 to 1,500 gallons/min), respectively. The optimum flow rate and operating pressures vary as a function of the casing and wellbore sizes, wellbore section length, available pumping equipment, and fluid properties of the fluidic material being pumped. The optimum flow rate and operating pressure are preferably determined using conventional empirical methods.

The hardenable fluidic sealing material 305 may be any number of conventional commercially available hardenable fluidic sealing materials such as, for example, slag mix, cement or epoxy. In a preferred arrangement, the hardenable fluidic sealing material 305 is a blended cement prepared specifically for the particular well section being drilled from Halliburton Energy Services in Dallas, TX in order to provide optimal support for tubular member 210 while also maintaining optimum flow characteristics so as to minimize difficulties during the displacement of cement in the annular region 315. The optimum blend of the blended cement is preferably determined using conventional empirical methods. In several alternative arrangements, the hardenable fluidic sealing material 305 is compressible before, during, or after curing.

The annular region 310 is filled with the material 305 in sufficient quantities to ensure that, upon radial expansion of the tubular member 210, the annular region 310 of the new section 130 of the wellbore 100 will be filled with the material 305.

As illustrated in FIG. 4, once the annular region 310 has been adequately filled with the material 305, a plug 405, or other similar device, is introduced into the fluid passage 220, thereby fluidicly isolating the interior region 230 from the annular region 310. A non-hardenable fluidic material 315 is then pumped into the interior region 230 causing the interior region to pressurize. In this manner, the interior region 230 of the expanded tubular member 210 will not contain significant amounts of cured material 305. This also reduces and simplifies the cost of the entire process. Alternatively, the material 305 may be used during this phase of the process.

Once the interior region 230 becomes sufficiently pressurized, the tubular member 210 is plastically deformed, radially expanded, and extruded off of the expansion cone 205. During the extrusion process, the expansion cone 205 may be raised out of the expanded portion of the tubular member 210. During the extrusion process, the expansion cone 205 is raised at approximately the same rate as the tubular member 210 is expanded in order to keep the tubular member 210 stationary relative to the new wellbore section 130. In an alternative preferred arrangement, the extrusion process is commenced with the tubular member 210 positioned above the bottom of the new wellbore section 130, keeping the expansion cone 205 stationary, and allowing the tubular member 210 to extrude off of the expansion cone 205 and into the new wellbore section 130 under the force of gravity and the operating pressure of the interior region 230.

The plug 405 is placed into the fluid passage 220 by introducing the plug 405 into the fluid passage 225a at a surface location in a conventional manner. The plug 405 acts to fluidicly isolate the hardenable fluidic sealing material 305 from the non hardenable fluidic material 315.

The plug 405 may be one of any number of conventional commercially available devices for plugging a fluid passage such as, for example, Multiple Stage Cementer (MSC) latch-down plug, Omega latch-down plug or three-wiper latch-down plug modified in accordance with the teachings of the present disclosure. Preferably, the plug 405 is a MSC latch-down plug available from Halliburton

Energy Services in Dallas, TX.

After placement of the plug 405 in the fluid passage 220, the non hardenable fluidic material 315 is preferably pumped into the interior region 310 at pressures and flow rates ranging, for example, from approximately 2.758 x 10^3 to 68.947 x 10^3 KPa (400 to 10,000 psi) and 113.55 x 10^{-3} to 15.14 m^3/minute (30 to 4,000 gallons/min). In this manner, the amount of hardenable fluidic sealing material within the interior 230 of the tubular member 210 is minimized. After placement of the plug 405 in the fluid passage 220, the non hardenable material 315 is preferably pumped into the interior region 230 at pressures and flow rates ranging from approximately 3.447 x 10^3 to 62.052 x 10^3 KPa (500 to 9,000 psi) and 151.4 x 10^{-3} to 11.355 m^3/minute (40 to 3,000 gallons/min) in order to maximize the extrusion speed.

The apparatus 200 is adapted to minimize tensile, burst, and friction effects upon the tubular member 210 during the expansion process. These effects will be depend upon the geometry of the expansion cone 205, the material composition of the tubular member 210 and expansion cone 205, the inner diameter of the tubular member 210, the wall thickness of the tubular member 210, the type of lubricant, and the yield strength of the tubular member 210. In general, the thicker the wall thickness, the smaller the inner diameter, and the greater the yield strength of the tubular member 210, then the greater the operating pressures required to extrude the tubular member 210 off of the expansion cone 205.

For typical tubular members 210, the extrusion of the tubular member 210 off of the expansion cone 205 will begin when the pressure of the interior region 230 reaches, for example, approximately 3.447 x 10^3 to 62.052 x 10^3 KPa (500 to 9,000 psi).

During the extrusion process, the expansion cone 205 may be raised out of the expanded portion of the tubular member 210 at rates ranging, for example, from about 0 to 1.524 m/sec (0 to 5 ft/sec). In a preferred arrangement, during the extrusion process, the expansion cone 205 is raised out of the expanded portion of the tubular member 210 at rates ranging from about 0 to 609.6 x 10^{-3} m/s (0 to 2

ft/sec) in order to minimize the time required for the expansion process while also permitting easy control of the expansion process.

When the upper end portion 210d of the tubular member 210 is extruded off of the expansion cone 205, the outer surface of the upper end portion 210d of the tubular member 210 will preferably contact the interior surface of the lower end portion 115a of the casing 115 to form an fluid tight overlapping joint. The contact pressure of the overlapping joint may range, for example, from approximately 344.7 to 137.89 KPa (50 to 20,000 psi). In a preferred arrangement, the contact pressure of the overlapping joint ranges from approximately 2.758×10^3 to 68.947×10^3 KPa (400 to 10,000 psi) in order to provide optimum pressure to activate the annular sealing members 245 and optimally provide resistance to axial motion to accommodate typical tensile and compressive loads.

The overlapping joint between the existing casing 115 and the radially expanded tubular member 210 provides a gaseous and fluidic seal. The sealing members 245 optimally provide a fluidic and gaseous seal in the overlapping joint. Alternatively, the sealing members 245 are omitted.

The operating pressure and flow rate of the non-hardenable fluidic material 315 is controllably ramped down when the expansion cone 205 reaches the upper end portion 210d of the tubular member 210. In this manner, the sudden release of pressure caused by the complete extrusion of the tubular member 210 off of the expansion cone 205 can be minimized. The operating pressure is reduced in a substantially linear fashion from 100% to about 10% during the end of the extrusion process beginning when the expansion cone 205 is within about 1.524 m (5 feet) from completion of the extrusion process.

Alternatively, or in combination, a shock absorber is provided in the support member 225 in order to absorb the shock caused by the sudden release of pressure. The shock absorber may, for example, be any conventional commercially available shock absorber adapted for use in wellbore operations.

Alternatively, or in combination, an expansion cone catching structure is provided in the upper end portion 210d of the tubular member 210 in order to catch

or at least decelerate the expansion cone 205.

Once the extrusion process is completed, the expansion cone 205 is removed from the wellbore 100. Either before or after the removal of the expansion cone 205, the integrity of the fluidic seal of the overlapping joint between the upper end portion 210d of the tubular member 210 and the lower end portion 115a of the preexisting wellbore casing 115 is tested using conventional methods.

If the fluidic seal of the overlapping joint between the upper end portion 210d of the tubular member 210 and the lower end portion 115a of the casing 115 is satisfactory, then any uncured portion of the material 305 within the expanded tubular member 210 is then removed in a conventional manner such as, for example, circulating the uncured material out of the interior of the expanded tubular member 210. The expansion cone 205 is then pulled out of the wellbore section 130 and a drill bit or mill is used in combination with a conventional drilling assembly 505 to drill out any hardened material 305 within the tubular member 210. The material 305 within the annular region 310 is then allowed to fully cure.

As illustrated in Fig. 5, any remaining cured material 305 within the interior of the expanded tubular member 210 is then removed in a conventional manner using a conventional drill string 505. The resulting new section of casing 510 includes the expanded tubular member 210 and an outer annular layer 515 of the cured material 305.

As illustrated in FIG. 6, the bottom portion of the apparatus 200 including the shoe 215 and dart 405 may then be removed by drilling out the shoe 215 and dart 405 using conventional drilling methods.

As illustrated in FIG. 7, an apparatus 600 for forming a mono-diameter wellbore casing is then positioned within the wellbore casing 115 proximate the tubular member 210 that includes an expansion cone 605 and a support member 610. The outside diameter of the expansion cone 605 is substantially equal to the inside diameter of the wellbore casing 115. The apparatus 600 further includes a fluid passage 615 for conveying fluidic materials 620 out of the wellbore 100 that are displaced by the placement and operation of the expansion cone 605.

The expansion cone 605 is then driven downward using the support member 610 in order to radially expand and plastically deform the tubular member 210 and the overlapping portion of the tubular member 115. In this manner, as illustrated in FIG. 8, a mono-diameter wellbore casing is formed that includes the overlapping wellbore casings 115 and 210. Alternatively, the secondary radial expansion process is performed before, during, or after the material 515 fully cures. A conventional expansion device including rollers may be substituted for, or used in combination with, the apparatus 600.

More generally, as illustrated in FIG. 9, the method of FIGS. 1-8 is repeatedly performed in order to provide a mono-diameter wellbore casing that includes overlapping wellbore casings 115 and 210a-210e. The wellbore casing 115, and 210a-210e preferably include outer annular layers of fluidic sealing material. In this manner, a mono-diameter wellbore casing may be formed within the subterranean formation that extends for tens of thousands of feet. More generally still, the teachings of FIGS. 1-9 may be used to form a mono-diameter wellbore casing, a pipeline, a structural support, or a tunnel within a subterranean formation at any orientation from the vertical to the horizontal.

The formation of a mono-diameter wellbore casing, as illustrated in FIGS. 1-9, is further provided as disclosed in one or more of the following: (1) U.S. patent application serial no. 09/454,139, attorney docket no. 25791.03.02, filed on 12/3/1999, (2) U.S. patent application serial no. 09/510,913, attorney docket no. 25791.7.02, filed on 2/23/2000, (3) U.S. patent application serial no. 09/502,350, attorney docket no. 25791.8.02, filed on 2/10/2000, (4) U.S. patent application serial no. 09/440,338, attorney docket no. 25791.9.02, filed on 11/15/1999, (5) U.S. patent application serial no. 09/523,460, attorney docket no. 25791.11.02, filed on 3/10/2000, (6) U.S. patent application serial no. 09/512,895, attorney docket no. 25791.12.02, filed on 2/24/2000, (7) U.S. patent application serial no. 09/511,941, attorney docket no. 25791.16.02, filed on 2/24/2000, (8) U.S. patent application serial no. 09/588,946, attorney docket no. 25791.17.02, filed on 6/7/2000, (9) U.S. patent application serial no. 09/559,122, attorney docket no. 25791.23.02, filed on

4/26/2000, (10) PCT patent application serial no. PCT/US00/18635, attorney docket no. 25791.25.02, filed on 7/9/2000, (11) U.S. provisional patent application serial no. 60/162,671, attorney docket no. 25791.27, filed on 11/1/1999, (12) U.S. provisional patent application serial no. 60/154,047, attorney docket no. 25791.29, filed on 9/16/1999, (13) U.S. provisional patent application serial no. 60/159,082, attorney docket no. 25791.34, filed on 10/12/1999, (14) U.S. provisional patent application serial no. 60/159,039, attorney docket no. 25791.36, filed on 10/12/1999, (15) U.S. provisional patent application serial no. 60/159,033, attorney docket no. 25791.37, filed on 10/12/1999, (16) U.S. provisional patent application serial no. 60/212,359, attorney docket no. 25791.38, filed on 6/19/2000, (17) U.S. provisional patent application serial no. 60/165,228, attorney docket no. 25791.39, filed on 11/12/1999, (18) U.S. provisional patent application serial no. 60/221,443, attorney docket no. 25791.45, filed on 7/28/2000, (19) U.S. provisional patent application serial no. 60/221,645, attorney docket no. 25791.46, filed on 7/28/2000, (20) U.S. provisional patent application serial no. 60/233,638, attorney docket no. 25791.47, filed on 9/18/2000, (21) U.S. provisional patent application serial no. 60/237,334, attorney docket no. 25791.48, filed on 10/2/2000, and (22) U.S. provisional patent application serial no. ____________, attorney docket no. 25791.52, filed on 1/3/2001, the disclosures of which are incorporated herein by reference.

Alternatively, the fluid passage 220 in the shoe 215 is omitted. In this manner, the pressurization of the region 230 is simplified. Alternatively, the annular body 515 of the fluidic sealing material is formed using conventional methods of injecting a hardenable fluidic sealing material into the annular region 310.

Referring to FIGS. 10-11, in an alternative arrangement, an apparatus 700 for forming a mono-diameter wellbore casing is positioned within the wellbore casing 115 that includes an expansion cone 705 having a fluid passage 705a that is coupled to a support member 710.

The expansion cone 705 preferably further includes a conical outer surface 705b for radially expanding and plastically deforming the overlapping portion of the tubular member 115 and the tubular member 210. The outside diameter of the

expansion cone 705 is substantially equal to the inside diameter of the pre-existing wellbore casing 115.

The support member 710 is coupled to a slip joint 715, and the slip joint is coupled to a support member 720. As will be recognized by persons having ordinary skill in the art, a slip joint permits relative movement between objects. Thus, in this manner, the expansion cone 705 and support member 710 may be displaced in the longitudinal direction relative to the support member 720. The slip joint 710 permits the expansion cone 705 and support member 710 to be displaced in the longitudinal direction relative to the support member 720 for a distance greater than or equal to the axial length of the tubular member 210. In this manner, the expansion cone 705 may be used to plastically deform and radially expand the overlapping portion of the tubular member 115 and the tubular member 210 without having to reposition the support member 720.

The slip joint 715 may be any number of conventional commercially available slip joints that include a fluid passage for conveying fluidic materials through the slip joint. In a preferred arrangement, the slip joint 715 is a pumper sub commercially available from Bowen Oil Tools in order to optimally provide elongation of the drill string.

The support member 710, slip joint 715, and support member 720 further include fluid passages 710a, 715a, and 720a, respectively, that are fluidicly coupled to the fluid passage 705a. During operation, the fluid passages 705a, 710a, 715a, and 720a preferably permit fluidic materials 725 displaced by the expansion cone 705 to be conveyed to a location above the apparatus 700. In this manner, operating pressures within the subterranean formation 105 below the expansion cone are minimized.

The support member 720 further preferably includes a fluid passage 720b that permits fluidic materials 730 to be conveyed into an annular region 735 surrounding the support member 710, the slip joint 715, and the support member 720 and bounded by the expansion cone 705 and a conventional packer 740 that is coupled to the support member 720. In this manner, the annular region 735 may be

pressurized by the injection of the fluids 730 thereby causing the expansion cone 705 to be displaced in the longitudinal direction relative to the support member 720 to thereby plastically deform and radially expand the overlapping portion of the tubular member 115 and the tubular member 210.

During operation, as illustrated in FIG. 10, the apparatus 700 is positioned within the preexisting casing 115 with the bottom surface of the expansion cone 705 proximate the top of the tubular member 210. During placement of the apparatus 700 within the preexisting casing 115, fluidic materials 725 within the casing are conveyed out of the casing through the fluid passages 705a, 710a, 715a, and 720a. In this manner, surge pressures within the wellbore 100 are minimized.

The packer 740 is then operated in a well-known manner to fluidicly isolate the annular region 735 from the annular region above the packer. The fluidic material 730 is then injected into the annular region 735 using the fluid passage 720b. Continued injection of the fluidic material 730 into the annular region 735 preferably pressurizes the annular region and thereby causes the expansion cone 705 and support member 710 to be displaced in the longitudinal direction relative to the support member 720.

As illustrated in FIG. 11, the longitudinal displacement of the expansion cone 705 in turn plastically deforms and radially expands the overlapping portion of the tubular member 115 and the tubular member 210. In this manner, a mono-diameter wellbore casing is formed that includes the overlapping wellbore casings 115 and 210. The apparatus 700 may then be removed from the wellbore 100 by releasing the packer 740 from engagement with the wellbore casing 115, and lifting the apparatus 700 out of the wellbore 100.

In an alternative arrangement of the apparatus 700, the fluid passage 720b is provided within the packer 740 in order to enhance the operation of the apparatus 700.

Alternatively, the fluid passages 705a, 710a, 715a, and 720a are omitted. In this manner, the region of the wellbore 100 below the expansion cone 705 is pressurized and one or more regions of the subterranean formation 105 are fractured

to enhance the oil and/or gas recovery process.

Referring to FIGS. 12-15, an apparatus 800 is positioned within the wellbore casing 115 that includes an expansion cone 805 having a fluid passage 805a that is releasably coupled to a releasable coupling 810 having fluid passage 810a.

The fluid passage 805a is preferably adapted to receive a conventional ball, plug, or other similar device for sealing off the fluid passage. The expansion cone 805 further includes a conical outer surface 805b for radially expanding and plastically deforming the overlapping portion of the tubular member 115 and the tubular member 210. In a preferred arrangement, the outside diameter of the expansion cone 805 is substantially equal to the inside diameter of the pre-existing wellbore casing 115.

The releasable coupling 810 may be any number of conventional commercially available releasable couplings that include a fluid passage for conveying fluidic materials through the releasable coupling. In a preferred arrangement, the releasable coupling 810 is a safety joint commercially available from Halliburton in order to optimally release the expansion cone 805 from the support member 815 at a predetermined location.

A support member 815 is coupled to the releasable coupling 810 that includes a fluid passage 815a. The fluid passages 805a, 810a and 815a are fluidicly coupled. In this manner, fluidic materials may be conveyed into and out of the wellbore 100.

A packer 820 is movably and sealingly coupled to the support member 815. The packer may be any number of conventional packers. In a preferred arrangement, the packer 820 is a commercially available burst preventer (BOP) in order to optimally provide a sealing member.

During operation, as illustrated in FIG. 12, the apparatus 800 is positioned within the preexisting casing 115 with the bottom surface of the expansion cone 805 proximate the top of the tubular member 210. During placement of the apparatus 800 within the preexisting casing 115, fluidic materials 825 within the casing are conveyed out of the casing through the fluid passages 805a, 810a, and 815a. In this

manner, surge pressures within the wellbore 100 are minimized. The packer 820 is then operated in a well-known manner to fluidicly isolate a region 830 within the casing 115 between the expansion cone 805 and the packer 820 from the region above the packer.

As illustrated in FIG. 13, the releasable coupling 810 is then released from engagement with the expansion cone 805 and the support member 815 is moved away from the expansion cone. A fluidic material 835 may then be injected into the region 830 through the fluid passages 810a and 815a. The fluidic material 835 may then flow into the region of the wellbore 100 below the expansion cone 805 through the valveable passage 805b. Continued injection of the fluidic material 835 may thereby pressurize and fracture regions of the formation 105 below the tubular member 210. In this manner, the recovery of oil and/or gas from the formation 105 may be enhanced.

As illustrated in FIG. 14, a plug, ball, or other similar valve device 840 may then be positioned in the valveable passage 805a by introducing the valve device into the fluidic material 835. In this manner, the region 830 may be fluidicly isolated from the region below the expansion cone 805. Continued injection of the fluidic material 835 may then pressurize the region 830 thereby causing the expansion cone 805 to be displaced in the longitudinal direction.

As illustrated in FIG. 15, the longitudinal displacement of the expansion cone 805 plastically deforms and radially expands the overlapping portion of the pre-existing wellbore casing 115 and the tubular member 210. In this manner, a mono-diameter wellbore casing is formed that includes the pre-existing wellbore casing 115 and the tubular member 210. Upon completing the radial expansion process, the support member 815 may be moved toward the expansion cone 805 and the expansion cone may be re-coupled to the releasable coupling device 810. The packer 820 may then be decoupled from the wellbore casing 115, and the expansion cone 805 and the remainder of the apparatus 800 may then be removed from the wellbore 100.

In a preferred arrangement, the displacement of the expansion cone 805 also

pressurizes the region within the tubular member 210 below the expansion cone. In this manner, the subterranean formation surrounding the tubular member 210 may be elastically or plastically compressed thereby enhancing the structural properties of the formation.

Although illustrative embodiments of the invention have been shown and described, a wide range of modification, changes and substitution is contemplated in the foregoing disclosure within the scope of the claims. Accordingly, it is appropriate that the appended claims be construed broadly.

Claims

1. A method of radially expanding an overlapping joint between a wellbore casing and a tubular liner, comprising:

positioning an expansion cone within the wellbore casing above the overlapping joint;

sealing off a region within the wellbore casing above the expansion cone;

releasing the expansion cone;

displacing the expansion cone by pressurizing an annular region; and

pressurizing the interior of the tubular liner.

2. An apparatus for radially expanding an overlapping joint between a wellbore casing and a tubular liner, comprising:

means for positioning an expansion cone within the wellbore casing above the overlapping joint;

means for sealing off a region within the wellbore casing above the expansion cone;

means for releasing the expansion cone;

means for displacing the expansion cone by pressurizing an annular region; and

means for pressurizing the interior of the tubular liner.

3. A method of radially expanding an overlapping joint between first and second tubular members, comprising:

positioning an expansion cone within the first tubular member above the overlapping joint;

sealing off a region within the first tubular member above the expansion cone;

releasing the expansion cone;

displacing the expansion cone by pressurizing an annular region; and

pressurizing the interior of the second tubular member.

4. An apparatus for radially expanding an overlapping joint between first and second tubular members, comprising:

means for positioning an expansion cone within the first tubular member above the overlapping joint;

means for sealing off a region within the first tubular member above the expansion cone;

means for releasing the expansion cone;

means for displacing the expansion cone by pressurizing an annular region; and

means for pressurizing the interior of the second tubular member.